S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion, establishing the method and avoided cost calculation for **CONSUMERS ENERGY COMPANY** to fully comply with the Public Utility Regulatory Policies Act of 1978, 16 USC 2601 *et seq*.	)	Case No. U-18090

At the May 31, 2017 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Sally A. Talberg, Chairman
Hon. Norman J. Saari, Commissioner
Hon. Rachael A. Eubanks, Commissioner

OPINION AND ORDER

History of Proceedings

The Commission opened this docket in an order issued on May 3, 2016 (May 3 order), and directed Consumers Energy Company (Consumers) to file proposed avoided cost calculation methods and costs in accordance with the requirements of the Public Utility Regulatory Policies Act of 1978, PL 95–617; 92 Stat 3117 (PURPA) and the May 3 order. In its filing, Consumers was instructed to provide avoided cost calculations using: (1) the hybrid proxy plant method proposed in the PURPA report;[1] (2) the transfer price method developed under 2008 PA 295

[1] In an order issued on October 27, 2015, in Case No. U-17973, the Commission opened an investigation into issues concerning PURPA avoided costs. After a series of meetings and a round of comments, the investigation culminated on April 8, 2016, when the Commission Staff (Staff) filed a final report (PURPA Report).

(Act 295); and (3) another method, if any, that the company wished to propose. Consumers was also directed to file a proposed Standard Offer tariff, including applicable design capacity.

Pursuant to the May 3 order, Consumers filed various avoided cost methods and costs on June 17, 2016. A prehearing conference was held by Administrative Law Judge Mark E. Cummins (ALJ) on July 21, 2016. At the prehearing conference, the ALJ granted petitions to intervene filed by the Michigan Environmental Council (MEC), Independent Power Producers Coalition of Michigan (IPPC), Cadillac Renewable Energy, LLC, Genesee Power Station Limited Partnership, Grayling Generating Station Limited Partnership, and T.E.S. Filer City Limited Partnership, (collectively, Cadillac), Michigan Power Limited Partnership, and Ada Cogeneration Limited Partnership (together, MPLP), Environmental Law & Policy Center, Ecology Center, Solar Energy Industries Association, and Vote Solar (collectively, ELPC), and Great Lakes Renewable Energy Association (GLREA). The Staff also participated in the proceedings.

An evidentiary hearing was conducted on December 8, 2016. The parties filed briefs and reply briefs, and on March 10, 2017, the ALJ issued his Proposal for Decision (PFD). On March 24, 2017, Consumers, the IPPC, GLREA, and ELPC filed exceptions to the PFD. On April 7, 2017, these parties filed replies to exceptions. The record in this proceeding consists of 528 pages of transcript and 71 exhibits that were admitted into evidence.

<u>Background</u>

On March 17, 1981, the Commission issued an order in Case No. U-6798, to commence implementation of the provisions of Section 210 of PURPA (16 USC 824a–3), which requires, among other things, that the Commission ~~to~~ establish the avoided cost amounts that an electric utility is obligated to pay to certain Qualifying Facilities (QFs). As defined in PURPA, a QF is a small power production facility or cogeneration facility that has a right to be served by, and sell to, its host electric utility at the utility's avoided cost. Cogeneration QFs produce electric energy and steam or other forms of energy, which are used for industrial, commercial, or cooling purposes. There is no maximum size limitation for PURPA qualification for cogeneration facilities. Small power production facilities are defined as facilities that use biomass, waste, or renewable resources, including wind, solar, and water, to produce electric power, and which, together with other facilities at the same site, have a generating capacity equal to or less than 80 megawatts (MW).[2] *See*, 18 CFR 292.101.

PURPA requires electric utilities to purchase the energy offered by QFs at rates that are "just and reasonable to the electric consumer of the electric utility and in the public interest" and that do not "discriminate against qualifying cogeneration and small power production facilities." 18 CFR 292.304(a)(1)-(2). However, electric utilities are not required "to pay more than the avoided costs for purchases." "Avoided costs" are defined as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 CFR 292.101(b)(6).

In its evaluation of avoided costs, the Commission is required, to the extent it can, to consider the following criteria, set forth in 18 CFR 292.304(e):

> (1) Data regarding the utility's cost structure and plans to add capacity;
> (2) The availability of capacity or energy from a qualifying facility during daily and seasonal peak periods, including:
> (i) The ability of the utility to dispatch the qualifying facility;
> (ii) The reliability of the QF;

[2] Pursuant to the 2005 Energy Policy Act amendments to PURPA, and Federal Energy Regulatory Commission (FERC) Order 688, QFs larger than 20 MW are presumed to have non-discriminatory access to regional markets. Thus, a host utility may apply to the FERC to terminate its obligation to purchase from QFs with net capacity in excess of 20 MW. Consumers is excused from the mandatory purchase obligation from these larger QFs. *See*, FERC Docket No. QM12-3-000, issued April 24, 2012.

> (iii) Contract terms;
> (iv) The extent to which scheduled outages of the qualifying facility can be coordinated with scheduled outages of the utility's facilities;
> (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies;
> (vi) The individual and aggregate value of energy and capacity from QFs on the electric utility's system;
> (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from QFs.
> (3) The relationship of the availability of energy or capacity from the QF to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use.
> (4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

Finally, FERC regulations require the establishment of Standard Offer rates for utility purchases from QFs with a design capacity of 100 kilowatts (kW) or less. The 100 kW size limit is a floor for Standard Offers, and uniform contracts and rates for QFs larger than 100 kW may be established.

By 1993, the Commission had issued over 20 orders approving PURPA contracts, with avoided costs calculated on the basis of a proxy coal-fired generating unit. In 2016, the Commission noted that it had been over two decades since avoided cost rates were developed and that, in light of the significant changes in the energy landscape and the imminent expiration of many of the original PURPA contracts, it was an opportune time to undertake a comprehensive reexamination of PURPA, with a focus on identifying appropriate, updated methods for establishing avoided costs.

<u>Discussion</u>

The ALJ provided a detailed overview of the record and positions of the parties that will not be repeated here. *See*, PFD, pp. 6-29. The ALJ determined that there were six issues that require resolution in this proceeding: (1) Consumers' avoided capacity costs; (2) Consumers' avoided energy costs; (3) Standard Offer tariff language, including contract length, prices, and design capacity; (4) the appropriate planning horizon for establishing avoided cost rates; (5) miscellaneous adjustments to avoided cost, *i.e.* lines losses, renewable energy credits (RECs), and other benefits; and (6) appropriate stand-by rates and utility charges for other services and matters for future PURPA reviews. These issues are addressed *ad seriatim.*

1. Planning Horizon and Avoided Capacity and Energy Costs

The Staff proposed a hybrid proxy plant approach for determining Consumers' avoided costs if capacity is required during a 10-year planning period. The Staff's method combines a natural gas combustion turbine (NGCT) proxy unit for capacity, and it allows a QF to choose among three options for the energy component. 2 Tr 157-162. If Consumers' forecast shows that no capacity is needed during the entire 10-year planning period, the Staff proposed that the company submit a filing so indicating, and the Standard Offer capacity rate for new QFs would then be adjusted to the Midcontinent Independent System Operator, Inc. (MISO) planning reserve auction (PRA) price. Nevertheless, for existing QFs with contracts that expire, the Staff recommended that these facilities have their contracts renewed at the full standard rate, whether or not the company forecasts a need for capacity. 2 Tr 157. The Staff posited that because the capacity supplied by existing QFs is already taken into account in the company's planning, it was appropriate to continue the contracts at the full avoided cost rate. The Staff recommended that if any capacity shortfall is projected over the 10-year planning horizon, QFs should be compensated for both capacity and energy.

The Staff contended that the use of an NGCT unit as a proxy for the cost of capacity was appropriate because this type of unit could be built quickly, at a relatively low cost, and an NGCT can be cycled on and off as needed. The Staff's proposal also recognizes zonal resource credits (ZRCs) that MISO uses for crediting effective load carrying capability (ELCC) on-peak. Specifically, the Staff's proposed method considers daily and seasonal peak periods using MISO's ELCC to determine the amount of capacity credit provided by wind and solar QFs. The ELCC is a mechanism that credits capacity based on historic on-peak availability that can be converted to ZRCs. 2 Tr 153-154; Exhibit S-5.

For energy, the Staff proposed that a QF select one of three options: (1) locational marginal price (LMP) at the time of delivery; (2) the utility's LMP forecast over the contract period; or (3) payment based on the forecasted variable cost of a natural gas combined cycle (NGCC) unit as determined by the model used to calculate transfer prices pursuant to Act 295 for the period of the contract. The Staff noted that to obtain lower-cost energy, a utility would be more likely to build an NGCC than a NGCT; thus, the use of an NGCC unit as a proxy for avoided energy cost was appropriate. In addition:

> All 3 of Staff's proposed options would also include the fixed investment cost attributable to energy (ICE) based on a natural gas combustion turbine (CT). 2 TR 161. The rationale is that to benefit from the cheaper energy costs of an NGCC, the difference between the capital costs of a CT and NGCC should be accounted for in the avoided cost model. Exhibit S-6. This difference is paid on a volumetric basis and is added to the energy payment.

Staff's initial brief, p. 6.

In its reply brief, the Staff maintained that its hybrid proxy method was the most appropriate means to establish avoided cost, but nevertheless raised concerns about whether the inputs to the model were appropriate:

> First, the lowered proposed avoided costs is concerning not just to IPPC, but Staff as well, in light of the requirement at Section 210 of PURPA to encourage offers to QFs. IPPC Initial Brief, pp 7-8. This is not due to a fault in Staff's model, however, but due to Staff altering its inputs with respect to the energy calculation to more closely align with the inputs provided by Consumers. The modified inputs

> are: plant size, plant capacity factor, heat rate, natural gas price forecast (fuel cost), fixed charge rate, fixed operations and maintenance (O&M) cost and capital costs. Each modification Staff made to the transfer price model input assumptions used in this case contributed to a lower avoided energy cost than is found on recent transfer price schedules. These inputs also change the CT capacity model outputs. The use of the input assumptions associated with transfer price schedules would result in an estimated avoided energy cost similar to the energy price associated with the transfer price.

Staff's reply brief, p. 2. In light of its concerns about the inputs to its hybrid proxy plant model, the Staff concluded "it is reasonable for the Commission to give serious consideration to the transfer price schedule inputs as well as the inputs suggested in Consumers' application in terms of Staff's proposed option No. 3." Staff's reply brief, pp. 9-10.

In its application and testimony, Consumers proposed that the avoided cost for capacity be based on a sliding scale of the number of ZRCs the company was projecting to purchase in a given year. In cases where the company projected that there was no need for capacity during the planning period, Consumers would not pay for capacity from QFs, but the company would pay for any energy delivered at the actual or forecasted LMP. At the high end of the range, where capacity needs for the planning period are in excess of 1000 ZRCs, Consumers proposed to base the capacity payment on the economic carrying charge fixed cost of an NGCC plant, with the energy payment based on the lesser of the actual or forecasted LMP and the incremental cost of production for the NGCC plant.

In rebuttal, Consumers modified its position to one closer to that advocated by the Staff, albeit with some important revisions to the Staff's method:

> The Company's revised avoided cost methodology is based entirely on a NGCC proxy plant, where the capacity component is based on the levelized fixed cost of a NGCC plant and the energy component is either: (i) the lesser of the forecasted LMP or forecasted variable cost of a NGCC plant, or (ii) the lesser of the actual LMP or the actual variable cost of a NGCC plant, where actual or forecasted energy price compensation is per the choice of the QF.

Consumers' initial brief, p. 9.

Consumers agreed with the Staff that the company's capacity needs should be determined based on a 10-year planning horizon; however, it proposed that if capacity is needed in the first five years, QFs should be paid for capacity at the levelized cost of an NGCC unit. If no capacity need is forecasted in that five-year period, QFs should be paid for capacity at the amount established by MISO in its annual PRA. Consumers argued that it would be unjust to require capacity payments beginning the first year, if no capacity is needed until year nine or 10.

Consumers also contended that MISO's ZRC capacity structure should be used in determining the amount of capacity required, as well as the avoided cost for both the Standard Offer and negotiated power purchase agreements (PPAs), for all QFs. According to Consumers, if the MISO ZRC structure is not implemented, "the Company would be forced to purchase capacity that is not recognized by MISO in order to meet the MISO reliability requirements. This could result in the Company being forced to purchase additional capacity due to the QF providing less capacity in actuality than what was contracted for pursuant to avoided cost rates." Consumers' initial brief, p. 10.

Consumers argued that energy costs should not be levelized and should be paid based on projected amounts as shown in Exhibit A-14. Consumers posited that by levelizing the energy payment, as Staff proposed, "payments to QFs are front-loaded. . . . By making levelized payments for fuel and Operation and Maintenance ("O&M"), the Company and the Commission would effectively be asking the QF to manage year-to-year fluctuations in fuel and O&M expenses." Consumers' initial brief, p. 11.

ELPC agreed that the Staff's proposed method was the most reasonable starting point for calculating avoided costs, noting that "a combustion turbine is the best measure of the incremental cost the Company actually avoids by entering long-term QF contracts." ELPC's initial brief, p. 7. In addition, ELPC urged the Commission to reject Consumers' proposed five-year planning horizon for determining whether capacity is needed, on grounds that short-term planning discriminates against QFs by using a significantly shorter planning horizon than is used by the company and by failing to take into account long-term capacity savings. ELPC further pointed out that when a utility builds capacity it tends to be added in relatively large amounts, resulting in excess capacity for several years. "The perverse result . . . is that QFs will perpetually be caught in a cycle of low capacity values due to the nature of large-scale utility capacity acquisitions even though customers would save money if the utility procured capacity through smaller, incremental QF purchases." ELPC's initial brief, p. 11, citing 2 Tr 248.

ELPC also supported the Staff's recommended approach for calculating avoided energy costs, observing that using an NGCC unit as a proxy for energy appropriately reflects what Consumers would pay under a long-term PPA. ELPC added one caveat to its support for the Staff's avoided cost method: namely, that the Commission should set avoided cost at no less than Consumers' cost to meet any applicable integrated resource plans (IRP), customer demand, or renewable portfolio requirements. ELPC pointed to increased renewables requirements under 2016 PA 342 (Act 342), recommending that when a QF is providing capacity and energy to satisfy requirements such as those under Act 342, the avoided cost rate should be the greater of the Staff's hybrid proxy plant approach or the company's cost to build the same generation.

GLREA recommended a "transition method," which:

> identifies the timing and type of capacity needed, and estimates the cost of new plant built to serve those needs. The avoided costs associated with the new plant entry are the cost of new entry, or CONE avoided costs. The transition method blends current information (current market prices, e.g., LMPs) and future information (e.g., CONE).

GLREA's initial brief, p. 5, quoting 2 Tr 44-45. GLREA argued that, ultimately, avoided costs are best calculated using a comparative IRP approach that measures Consumers' long-range expansion plan without QF contracts to the same plan including QF contracts, with the difference equal to the avoided cost. While GLREA admitted that this approach is more complex than the proxy plant method, it nevertheless observed that Consumers is already undertaking IRP without QFs, thus including QFs in the modeling would not add significant time or difficulty to the process.

IPPC argued that Consumers' proposed method, relying largely on LMP and the MISO PRA to obtain incremental capacity and energy, discriminates against QFs, in violation of the requirements of PURPA. IPPC emphasized that the FERC and the courts have long recognized that the use of a utility's embedded cost underestimates the true avoided cost, and "the market-based methodology proposed by Consumers is based on the premise that its customers should not pay more for energy and capacity than 'what the Company could actually purchase' if it was looking for the cheapest source of residual supply[.]" Thus, Consumers' proposed method does not reflect the company's true avoided cost and is therefore contrary to the intent of PURPA.

IPPC also objected to the Staff's proposed method for calculating avoided cost, noting that it also relies extensively on short-term market pricing that discriminates against QFs. IPPC pointed to the contrast between Consumers' and the Staff's proposals and the avoided cost rates paid for company-owned projects and PPAs pursuant to the current transfer prices under Act 295. *See*, Exhibit IPPC-3.

According to the IPPC:

> [T]he Commission has adopted a cost pricing methodology for renewable energy, the Transfer Price Schedule, which would clearly meet the Federal requirements for a full avoided cost methodology. To the extent, however, that this methodology is only applied to recompensing the utility and for non-QF renewable energy projects, then it is being discriminatorily applied.

IPPC's initial brief, p. 42.

IPPC further pointed out that transfer price continues to be relevant because the Act 342 amendments to Act 295 preserve the transfer price mechanism, increase the renewable portfolio standard (RPS) from 10% to 15% by 2021, and the amendments establish a goal that 35% of Michigan's energy needs be supplied by renewables and energy efficiency by 2025.

Cadillac and MPLP did not take a position on the proposed avoided cost methods, but stated that they did not support any adjustments to current PURPA contracts, and new avoided cost rates developed as a result of this proceeding should only apply to new contracts.

After reviewing the various proposals and arguments presented by the parties, the ALJ found that the Staff's hybrid proxy plant method "appears to be more in line with the intent of PURPA and the State of Michigan's application of that statute to utilities within the state." PFD, p. 30. Specifically, with respect to avoided capacity costs, the ALJ found the Staff's proposed NGCT was "both logical and best supported on the record[,]" noting that both ELPC and GLREA agreed with this approach. He also found the Staff's recommendation to take into account ZRCs for intermittent resources like wind and solar was both appropriate and supported. And, the ALJ agreed with the Staff's recommendations that:

> (1) any electric capacity Consumers may need over its current 10-year planning horizon should come from either existing or new/willing QF suppliers, if possible, (2) all of the QFs currently supplying capacity to the utility should have their expiring contracts renewed at the full standard offer rate -- as opposed to the PRA--regardless of whether the company expresses that it has additional capacity needs based on its then-current 10-year planning horizon, and (3) with regard to any new QFs, capacity payments would be set at the PRA if, indeed, Consumers' capacity need over the 10-year capacity planning period has been fully satisfied.

PFD, pp. 31-32, citing 2 Tr 160-161.

The ALJ rejected IPPC's contention that the current Act 295 transfer price was the appropriate avoided cost, finding that application of the transfer price would require the company and ratepayers to pay excessive prices for capacity. Finally, the ALJ noted that there was no significant disagreement concerning the use of a 10-year planning horizon with firm capacity determinations made over a five-year target range.

With respect to the energy portion of avoided cost, the ALJ again agreed with the Staff's proposal to give QFs the option of payment based on actual LMP, forecasted LMP, or avoided cost of an NGCC plant, with an ICE adder applied to each of these methods. The ALJ determined that the Staff's proposal would protect Consumers, its customers, and the QFs from under- or overinflated energy prices.

Consumers takes exception to the ALJ's recommendations to adopt the Staff's proposed method for calculating avoided capacity and energy costs. Specifically, Consumers objects to the use of any proxy plant, contending that because the company has no current plans to build an NGCT or NGCC generating plant, neither of these units is an appropriate proxy. Nevertheless, Consumers posits that if it were to build a plant, it would select an NGCC because it would be most economical means to supply large amounts of capacity; it would simplify the avoided cost calculation, and it would protect Consumers' ratepayers. Consumers adds that it is inconsistent to use one generation technology (NGCT) for calculating avoided capacity costs and a different technology (NGCC) for calculating energy costs. Consumers reiterates that avoided costs should be based on the unit that is actually avoided, which, in the company's case would be an NGCC plant.

In response, ELPC points out that several witnesses, and even Consumers' initial proposal, recognized that an NGCT unit was the most likely addition to meet an incremental capacity shortfall. ELPC further points out that Consumers' claim that it would build an NGCC unit to address a significant shortage in capacity is contrary to PURPA's intent, "which is to fill in incremental capacity shortfalls and defer small capacity additions with purchases from QFs. See e.g., 18 CFR § 292.304(e)(3)." ELPC's replies to exceptions, p. 3.

Consumers also takes exception to the approval of the Staff's proposal to use the ZRC capacity structure only for intermittent resources like solar and wind. According to Consumers, many QF technologies, including hydro and biomass, operate in a similar fashion to a conventional baseload plant, thus capacity adjustments should be applied to all QFs. Consumers adds that for certain technologies, such as landfill gas and biomass, MISO uses an historical forced outage rate which should likewise be applied here.

Consumers takes exception to the ALJ's recommendation that contracts with existing QFs should be approved at the full avoided cost rate, rather than the PRA, regardless of whether the company projects a need for capacity in the next 10 years. Consumers maintains that it should not be required to pay for capacity that it does not need, and even if the company foresees a need for additional capacity now, this circumstance could change due to additional energy efficiency or renewable energy requirements under Act 342. Consumers reiterates that avoided cost should not exceed the MISO PRA price, for new or existing QFs, if no capacity is required in the next five years.

ELPC replies that Consumers again misses the point of PURPA, noting that the capacity costs that are avoided include the deferral of a new unit, even if there is no immediate need for new capacity. "Contrary to its assertions, costs avoided by capacity deferrals do not require Consumers to pay for capacity it does not need. Rather, it provides an appropriate incentive structure for Consumers to add incremental capacity to avoid costly large-scale self-build capacity additions that may not be economical for customers." ELPC's replies to exceptions, p. 4.

With respect to avoided energy cost, Consumers repeats its objection to the Staff's ICE adder, arguing that ICE does not represent any of the avoided cost of energy. Consumers posits that if LMP or the variable cost of an avoided energy resource is the cost of energy associated with the capacity resource, then one of the two is the avoided cost for energy. Consumers further claims that the fixed costs represented by the ICE adder should not be recovered on a volumetric basis, but rather should be included as part of avoided capacity costs, otherwise there is a mismatch. Consumers further criticizes the ICE payment as unsupported by any economic analysis, and the company points out that the Staff's inclusion of an ICE payment is not consistent with any other avoided cost calculation method.

ELPC replies that the ICE payment is "necessary to reflect the fact that if the energy cost Consumers avoids is the variable cost of an NGCC plant, Consumers has necessarily made the investment to build an NGCC plant." *Id.*

Finally, Consumers takes exception to the Staff's proposal to levelize fuel and other variable cost payments, reiterating that "Staff's proposal creates clear deviations between variable payments and variable costs of QFs." Consumers' exceptions, p. 10. Moreover, Consumers objects to the Staff's proposal to escalate the purportedly levelized payments, contending that by both levelizing and escalating variable payment amounts, the Staff is essentially double-counting the increase. Consumers therefore urges the Commission to adopt the data inputs and avoided energy cost payments set forth in Exhibit A-14.

IPPC also takes exception to the ALJ's recommendation to adopt the Staff's method for calculating avoided cost. As an initial matter, IPPC notes that the ALJ adopted this method for "QFs located in Consumers' service territory" whereas PURPA requires a utility to pay for energy from any QF that can deliver the energy, whether or not the QF is located in the service territory.

Second, IPPC contends that the use of an NGCT unit as a proxy for capacity is unsuitable because it seeks to model the lowest-cost proxy for capacity, contrary to PURPA's intent. IPPC points out that for the company's renewable energy resources, the proxy unit used for capacity is an NGCC, resulting, in higher capacity prices paid to Consumers compared to QFs. According to IPPC, "rather than treating QFs in a non-discriminatory manner, as compared to the utilities' own resources, Staff's methodology seeks the lowest cost option." IPPC's exceptions, p. 5.

IPPC also points out that the ALJ should have rejected the Staff's claim that its hybrid proxy approach is identical to the method used to calculate transfer price, albeit with updated inputs. IPPC contends that there is nothing in the record that supports that claim because the Staff never provided inputs or results from its hybrid model; thus, no comparison to transfer prices can be made.

IPPC also raises concerns about the inputs to the Staff's avoided cost model, noting that even the Staff expressed reservations about the assumptions used, noting that although Consumers' proposed data was entered into the model, "Staff never intended to endorse Consumers' inputs as the only reasonable inputs." IPPC's exceptions, p. 8, quoting Staff's reply brief, p. 3. IPPC contends that these input assumptions are critical to arriving at an appropriate and non-discriminatory avoided cost. Thus, according to IPPC:

> [T]he Transfer Price Schedule inputs used for Consumers' own generation provides a more reasonable set of inputs and one that does not fall victim to the fault of discriminatory treatment of QFs, which both Consumers' inputs, and Staff's inputs do. However, as IPPC notes above, because Staff failed to run its model with the Transfer Price input assumptions, we have no evidence on the record that such input assumptions would produce a fair and reasonable avoided cost. The only model successfully shown to do that is the Transfer Price model.

IPPC's exceptions, p. 9.

Consumers replies that the transfer price under Act 295 is not appropriate for use as avoided cost under PURPA. Consumers argues that the purpose of transfer price under Act 295 is different than the purpose of establishing avoided cost under PURPA and that implementing transfer price in lieu of a more traditional avoided cost method, would result in avoided costs that are overstated. According to Consumers, Act 295 transfer price is simply a means of allocating costs for renewable energy between power supply and incremental cost of compliance, and does not reflect true avoided cost. Consumers further asserts that transfer price does not incorporate capacity credit and is uniform for all utilities in Michigan. Therefore, according to Consumers, transfer price does not reflect company-specific avoided costs as required by PURPA. Finally, Consumers contends that IPPC did not provide adequate support for the use of the transfer price method on the record.

Concerning the input data, Consumers repeats that there is no evidence in the record concerning the inputs to transfer price, and the only inputs to the NGCC model are what the company provided. Consumers argues that it would violate the Administrative Procedures Act, specifically MCL 24.285, for the Commission to adopt the inputs to transfer price as the inputs to the avoided cost calculation. And, Consumers reiterates that those inputs are inappropriate because they are general and not company-specific.

Next, IPPC takes exception to the ALJ's determination that contracts for new QFs should reflect the MISO PRA price, rather than full avoided cost rates, in the event that Consumers' ten-year forecast shows no need for capacity. According to IPPC, the ALJ's statement could be construed to mean that if the company had a plan to meet its capacity needs through a PPA with a non-QF or through new build, then the company could avoid contracting with available QFs. This, IPPC contends, would be at odds with PURPA's purpose to encourage the development of QF resources. IPPC requests that the Commission clarify that "the PRA applies only when the utility's 10-year plan shows no capacity need – that is, that the utility does not need to take any action over the next 10 years to address capacity." IPPC's exceptions, p. 10.

The Commission agrees with the ALJ and finds that the Staff's hybrid proxy method is the most appropriate model for calculating avoided costs pursuant to PURPA. As several parties point out, the purpose of PURPA, and the avoided cost calculation, is not to set prices that reflect the lowest-cost incremental capacity and energy, but to provide non-discriminatory treatment to QFs by setting prices that are just and reasonable, in the public interest, and that mirror what the utility would have paid if it purchased or built the resource itself. 18 CFR 292.101(b)(6). Thus, the Commission agrees with the Staff, IPPC, ELPC, and GLREA that Consumers' proposals for calculating avoided capacity and energy costs rely inappropriately on short-term market prices.

As acknowledged by the ALJ, the Commission also finds that PURPA avoided cost is a more detailed inquiry than transfer price, which, as Consumers points out, is primarily used to allocate Act 295 renewable energy costs between power supply and incremental costs of compliance. The Commission agrees with the Staff that in the event that Consumers requires additional capacity only, the company would theoretically build an NGCT unit. As the Staff argued, this type of unit could be built quickly, at a relatively low cost, and a NGCT can be cycled on and off when additional capacity is required. On the other hand, if the company requires additional energy, an NGCC unit would be the most appropriate generating unit due to the low cost of the energy produced.

Further, the Commission agrees with the Staff's recommendation that it is reasonable to apply ZRC capacity credits to intermittent QF resources (i.e., wind and solar) to reflect their availability during seasonal and daily peak times, although this issue should be revisited in the company's next

PURPA review. The Commission also agrees that the ICE payment added to energy cost is appropriate. As ELPC points out:

> The ICE adjustment is necessary to reflect the fact that if the energy cost Consumers avoids is the variable cost of an NGCC plant, Consumers has necessarily made the investment to build an NGCC plant. Incorporating the investment cost attributable to that energy does not, as Consumers contends, conflate capacity costs with energy costs. The ICE does not "double count" capacity because it is a measurement of the **difference in cost** between building a NGCT and a NGCC. . . . A NGCC is more expensive to build than a NGCT, and the ICE represents the difference (**and only the difference**) in cost between building the two units. The ICE is not, as Consumers argues, a cost of capacity –it is a component of Consumers' cost of energy from a NGCC.

ELPC's replies to exceptions, pp. 4-5, citing 2 Tr 43; 163-164 (emphasis in the original).

The Commission also agrees with the parties and the ALJ that a 10-year planning horizon is most appropriate for determining capacity requirements, that avoided costs established in this proceeding should only apply to new and renewed contracts, and that existing contracts should not be altered.

The Commission rejects Consumers' contention that only capacity required in the next five years should be considered for full avoided cost because, as the IPPC points out, Consumers uses a far longer planning horizon in making decisions about whether to purchase or build new conventional generation. In addition, as the ELPC argued, there is significant ratepayer value in deferring large, capacity additions through contracting with QFs for incremental capacity. The Commission also agrees that existing QFs with expiring contracts should have their contracts renewed at the full avoided cost rate, whether or not the company forecasts a capacity shortfall over the planning horizon. As the Staff, ELPC, and IPPC pointed out, the capacity and energy supplied by these QFs is already taken into account in the company's determinations about future capacity additions. And, the Commission finds it reasonable to escalate the levelized energy payments to recognize the fact that over the term of the contract, MISO energy prices will be set based on new market entries. The Commission also agrees that if no capacity is needed during the 10-year planning horizon, then Consumers shall make a filing so indicating, and the avoided cost for capacity shall be reset to the MISO PRA. The Commission disagrees with the IPPC's apparent claim that the utility's obligation to purchase capacity from QFs persists, even if no additional capacity need is forecasted.

The Commission finds that these conclusions best represent the proper approach to determining what Consumers would have paid if the company had built or purchased the energy and capacity itself. Moreover, the hybrid-proxy method proposed by the Staff and adopted here, along with the other determinations in this order, will ensure that QFs are not discriminated against in resource planning and contract arrangements.

While the Commission adopts the hybrid-proxy approach as the appropriate method for arriving at avoided cost, it nevertheless finds that, with respect to calculating final avoided cost amounts for capacity and energy, there is insufficient information in this record about the proper inputs to the models to arrive at an accurate determination. Considering the number of QFs with expiring contracts on Consumers' system, and the expectation that many of these contracts could be renewed for some period, it is essential that the Commission have a sufficient record on which to make the determination of avoided cost in compliance with the mandates of PURPA. Not only is the establishment of an accurate avoided cost necessary for existing and new QFs, but also for the Commission's benefit in evaluating PPAs and certificates of need for new generation that the company may present in the future. The Commission finds that the inputs to the NGCT proxy for capacity and the NGCC model for energy were not sufficiently examined in the proceeding. Accordingly, the Commission remands this case for the limited purposes of receiving into evidence the appropriate inputs for capacity, capacity factor, heat rate, projected fuel cost, and capital costs plus the amount of the ICE adder, for the Staff's hybrid proxy model.

Accordingly, the parties shall file proposed inputs for the NGCT and NGCC model by June 12, 2017. Parties shall file responses by June 19, 2017. A hearing shall be conducted by the ALJ on June 21, 2017, and the ALJ shall set a briefing schedule so that the record and briefs in the reopened case can be submitted to the Commission by July 5, 2017.

2. Standard Offer Tariff

The Standard Offer is a tariffed rate paid to QFs through a standard contract with the utility. PURPA regulations require electric utilities to establish standard rates for purchases from QFs with capacity of 100 kW or less, but the regulations also give state commissions the authority to apply the Standard Offer to larger projects. 18 CFR 292.304(c)(1) and (2). The availability of a standard tariff reduces transaction costs for individual projects, thus reducing barriers to entry, especially for developers of smaller QFs. The disputed issues include the method and inputs to the Standard Offer rate, planning horizon for capacity additions by QFs, design capacity for the Standard Offer, and contract length.

Consumers initially proposed to use the same tiered approach discussed above for the Standard Offer tariff for QFs with a design capacity of 100 kW or less. In rebuttal, Consumers adopted the NGCC proxy plant approach for capacity, with the energy component based on: (1) the lesser of forecasted LMP or forecasted variable cost of an NGCC plant; or (2) the lesser of actual LMP or actual variable costs of an NGCC plant. A QF could then opt for either of these methods for compensation for energy. Consumers' initial brief, p. 9. Consumers agreed that a 10-year planning horizon was appropriate, but again contended that if there is no need for capacity in the first five years of the planning period, QFs under the Standard Offer would receive capacity payments based on the MISO PRA. Consumers also adjusted its design capacity proposal to 1.5 MW or less, which it claimed would accommodate most small developers, including most hydro QFs that currently have contracts with the company. Finally, with respect to the length of the Standard Offer contract, Consumers proposed that the term be limited to five years where the QF opts for forecasted energy prices and 10 years in cases where the QF opts for actual energy prices. Exhibit A-12.

The Staff proposed several changes to the company's tariff and submitted its own Standard Offer in Exhibit S-1. As summarized by the ALJ, the Staff recommended:

> (1) begin immediately with a 2 MW cap on the standard offer tariff, which can be later set anywhere from 1 to 5 MW, depending on the potential level of capacity shown to be needed in Consumers' 10-year planning horizon, (2) provide QFs with line loss credits where applicable, while not limiting them to the initial 2.37% figure proposed by the utility, pending the receipt of additional support for that figure--as well as information regarding transmission savings, environmental compliance costs, etc.--in the context of the company's next biennial avoided cost review, (3) allow QFs that elect to provide capacity and energy by way of the standard offer tariff to choose which of the three energy payment proposals suggested by the Staff should be applied to their particular PPAs, (4) let those QFs participate in the two-prong capacity payment plan proposed by the Staff, under which QFs that are renewing their status receive the full standard offer tariff rate, and allowing QFs that are new to the system to be assigned the PRA-based rate if the utility is not viewed as being short of capacity during its then-applicable 10-year planning horizon, (5) reexamine the standard offer tariff as part of the company's biennial review process, (6) allow for *ex parte* review of all standard offer tariff-based contracts when submitted, and (7) give Consumers the opportunity to file a case to reduce the price used for standard offer agreements to the PRA level if its 10-year planning horizon calls for no new capacity.

PFD, pp. 34-35. In addition, the Staff recommended that QFs be given the option of a five-, 10-, or 15-year contract term.

As it did for non-Standard Offer contracts, ELPC agreed with the Staff's method for calculating avoided cost. ELPC further noted that limiting the Standard Offer to five years, as Consumers proposed, would violate PURPA's intent to encourage the development of QFs and that a minimum of 15 years is required to attract investment and financing. ELPC also recommended that the Standard Offer be made available to QFs of up to 20 MW, contending that larger QFs also benefit when transactions costs are reduced through the use of a standard contract.

IPPC again disagreed with Consumers' and the Staff's approaches to calculating avoided costs, reiterating that transfer price is the most appropriate method for making these determinations. IPPC agreed with the Staff and ELPC that contracts limited to five years violate the requirements of PURPA, and advocated that all QF contracts, whether Standard Offer or separately negotiated, be permitted a term of 20 years. GLREA agreed with IPPC and the Staff that five-year contracts do not comport with PURPA, but contended that contracts of 20 years or longer should be permitted. GLREA pointed to MCL 460.6j, which allows for QF contracts of 17.5 years or longer.

The ALJ found that the Staff's recommendations should largely be adopted, except that he determined that Standard Offer contracts should extend to 20 years as recommended by GLREA, IPPC, and ELPC. The ALJ found persuasive the claim that longer contracts would benefit both QFs and the company by allowing better access to investment and financing. The ALJ agreed with the Staff that the design capacity for the Standard Offer should be established at 2 MW, with the proviso that this cap should be revisited in the next PURPA review. The ALJ observed that the record lacked persuasive evidence to support Consumers' claim that QFs over 1.5 MW have sufficient experience and resources and therefore do not require a standard contract.

Consumers takes exception, repeating its objections to contracts longer than five years, contending that the company's capacity needs could change significantly in that time and that longer contracts could force the company to continue to purchase capacity it does not require. Consumers contends that the length of renewable energy PPAs under Act 295 are irrelevant because these contract terms reflect the need for RECs in the future. Consumers further posits that IPPC and GLREA misconstrue the language in Section 6j which only limits the time when the Commission can reconsider previously approved capacity charges for QFs.

GLREA takes exception, asserting that the Commission should recognize that contracts in excess of 20 years should be approved. GLREA points to the provision in MCL 460.6j that permits QF contracts to extend for the length of the financing period or 17.5 years. GLREA also observes that Consumers' current contract with the Midland Cogeneration Venture Partnership, LLC, is a 35-year agreement. GLREA therefore urges the Commission to adopt a contract length up to 35 years.

ELPC, GLREA, and IPPC take exception to limiting the design capacity for the Standard Offer to 2 MW. These parties reiterate that the Standard Offer should be made available to QFs up to 20 MW in size because the individual negotiations necessary for non-Standard Offer contracts can be costly in terms of time and expense. ELPC adds that Consumers failed to justify limiting the size of the Standard Offer. Conversely, Consumers maintains that the Standard Offer should be limited to 1.5 MW because a 20 MW limit on the Standard Offer could result in the company having to purchase more capacity than it needs

The Commission agrees with the ALJ's reasoning and conclusions and adopts the PFD on the issues concerning the Standard Offer contract. Specifically, the Commission agrees that the Staff's hybrid proxy method for determining avoided cost should also apply to the Standard Offer, QFs under the Standard Offer should be able to opt for a contract term up to 20 years, and that for now, the Standard Offer should be limited to QFs of 2 MW or less; however, this cap should be revisited in the company's next avoided cost filing. The Commission disagrees with GLREA that a 35-year option should be made available under the Standard Offer, noting that contracts extended beyond 20 years could be negotiated in a non-Standard Offer agreement and would likely only apply in rare circumstances.

As the Commission discussed above, this case is remanded for the taking of additional evidence on the appropriate inputs to the NGCT and NGCC models for avoided capacity and energy costs. As part of that reopened proceeding, parties may present updated Standard Offer tariffs, which should include forecasted LMP energy rates for five, 10, 15, and 20 years and proxy plant variable rate forecasts for the same incremental periods.

3. Other Avoided Costs and Benefits

The parties agreed generally that in addition to avoided energy and capacity costs, there are other potential avoided costs and benefits associated with QF power including reduced transmission costs and line losses, reduced air emissions and environmental compliance costs, and the hedging value resulting from the use of QFs. The parties also agreed that RECs that are generated by a QF should be considered, albeit with disagreement over how RECs should be assigned.

Consumers made several recommendations concerning these associated costs including: (1) other avoided costs should be included as long as they are not theoretical and can be quantified; (2) increased, rather than avoided, costs should be quantified and applied to the calculation as well, where appropriate; (3) RECs that are generated under the Standard Offer tariff should be assigned to the utility rather than the QF providing service; and (4) line-loss mitigation credits should be assigned a value of 2.37% of the power provided.

The Staff agreed that in the Standard Offer tariff, line-loss savings should be credited but that the credit should be higher than the 2.37% proposed by the company for QFs connected at lower-voltage where additional line-loss savings are realized. The Staff also agreed that under the

Standard Offer, RECs should go to Consumers, but for larger QFs, REC ownership should be subject to negotiation.

ELPC, GLREA, and IPPC objected to assigning RECs to the company, noting that this issue was addressed by the FERC in *Windham Solar LLC and Allco Finance Ltd*, 156 FERC P61,042, ¶ 4 (2016) (*Windham Solar*). According to ELPC, in *Windham Solar*, the FERC held that PURPA contracts are compensation for energy and capacity only, and a state commission cannot assign RECs as part of that contract. ELPC further argues that MCL 460.1037 recognizes RECs as distinct from renewable energy and points to the MIRECS tracking system where RECs are registered, sold, and traded. ELPC also recommended that the Commission open a proceeding to examine these additional avoided costs, which should be completed before the next avoided cost review.

The ALJ noted that the parties were in general agreement that additional avoided costs should be considered in both the Standard Offer and in negotiated agreements. The ALJ concurred with the Staff that line-loss credits should not be permanently fixed at 2.37% for all systems, noting that this issue should be subject to negotiation for larger QFs and should be revisited, along with other avoided costs, in the next PURPA review for the Standard Contract. Finally, the ALJ found that, under *Windham Solar*, RECs should be assigned to the QF to sell to the company or otherwise dispose of.

Consumers takes exception to the ALJ's recommendation with respect to the assignment of RECs. According to Consumers, *Windham Solar* does not require that RECs be assigned to the QF, it only determines that the state, and not the FERC, has the authority to assign RECs and decide how they are subsequently transferred. Consumers insists that because the company is required to purchase renewable energy from QFs, it would be unreasonable to assign any RECs generated to the QF, or to require the company to purchase the RECs from the QF. In a related exception, ELPC requests that the Commission clarify that in the event that a negotiated agreement for RECs cannot be reached, then the RECs remain the property of the QF.

Consumers also takes issue with the ALJ's determination concerning other avoided costs, contending that it is not clear whether avoided transmission costs, hedging costs, reduced emissions and environmental compliance costs should be included in the avoided cost calculation. Consumers maintains that there is insufficient evidence in the record to quantify these costs and therefore the Commission should decline to include them in the avoided cost calculation at this time. ELPC recommends that the Commission find that the 2.37% line-loss credit Consumers proposes should be considered a rebuttable presumption until the next PURPA review.[3]

The Commission agrees with IPPC, ELPC, and GLREA's interpretation of *Windham Solar* concerning the ownership of RECs, thus, the amounts paid for energy and capacity do not include compensation for RECs. Accordingly, the QF may sell the RECs to the host utility or otherwise disposed of them at the QF's option.[4] The Commission agrees with the company that there is insufficient information in the record to quantify other avoided costs, except for line-loss credit, and that parties may include analyses of these costs in the next PURPA review proceeding. With respect to the line-loss credit, the Commission agrees with the Staff and ELPC that the credit should be set at 2.37% in the Standard Offer, until more information is available, presumably after

[3] GLREA contends that a 2.37% line-loss credit is unreasonable, arguing that Consumers generally includes line losses of over 8% in its electric rate cases. The Commission observes that GLREA first raises this issue in its exceptions and that there is no evidence in the record to support this claim.

[4] "The Commission has also held, however, that a state regulatory authority may not assign ownership of RECs to utilities based on a logic that the avoided cost rates in PURPA contracts already compensate QFs for RECs in addition to compensating QFs for energy and capacity, because the avoided cost rates are, in fact, compensation just for energy and capacity." *Windham Solar, supra,* ¶ 4.

the next PURPA avoided cost review. For non-Standard Offers, the line-loss credit should be negotiated.

4. Other Issues

With respect to stand-by rates and future PURPA reviews, the Staff pointed out that pursuant to Section 6v of Act 341, MCL 460.6v, for each electric utility that serves Michigan customers, the Commission must conduct a proceeding at a minimum of every five years that evaluates: (1) whether the rates paid to QFs are just and reasonable, as well as in the public interest, as defined by PURPA; and (2) whether the amounts charged by the utility, to QFs, for maintenance, backup, interruptible, and supplementary power, and other services are just and reasonable, and non-discriminatory. The Staff maintained that this proceeding should be considered the first five-year review for Consumers because it addressed all of the avoided cost issues. The Staff also proposed that avoided costs be reexamined every two years, noting:

> The proposal is consistent with 18 CFR § 292.302(b), which requires the companies to report every 2 years the utility's avoided cost data and capacity planning information for a 10 year period. At the time of the biennial report, the Commission may update the standard offer as necessary, during a contested case proceeding. The contested case proceeding would allow the Commission to update the cap for the utility's standard offer, depending on its capacity need in the succeeding 2 years and over the 10 year planning horizon.

Staff's initial brief, pp. 8-9.

With respect to stand-by rates and other matters that are part of the five-year review under Section 6v, the Staff pointed out that these issues are being addressed by the Stand-by Rates Workgroup that was established in the November 19, 2015 order in Case No. U-17735. In addition, the Staff argued that stand-by rates can be addressed in Consumers' next rate case.

The ALJ found that no party objected to the Staff's proposals; however, ELPC recommended that as part of the next review proceeding, the Staff should prepare a value of solar (VOS) analysis to initiate the process of evaluating technology-specific avoided costs for distributed solar generation. Because there was no apparent dispute over the Staff's or ELPC's proposals, the ALJ recommended their adoption.

Consumers takes exception to the recommendation concerning a VOS study. Consumers maintains that, while some elements of VOS may be inputs to an avoided cost calculation, VOS itself is not governed by PURPA and should therefore not be included in a biennial review. Consumers further points out that, based on the outcome of the Solar Work Group, there is a lack of consensus on the items to be included in VOS and on the appropriate calculation method. Consumers also claimed that ELPC's recommendation was an attempt to revisit the VOS method that has been previously addressed by the Commission and the Solar Working Group.

In reply, ELPC points out PURPA permits state commissions to set avoided costs for specific technologies like distributed solar generation, and it argues that a lack of consensus is insufficient reason to reject a VOS approach to calculating avoided cost for solar. ELPC further contends that there is extensive, recent research on valuation approaches and specific avoided costs for a VOS analysis in Michigan. ELPC adds that prior efforts concerning VOS were not focused on PURPA avoided costs, but that the outcomes from the Solar Working Group provide a reasonable starting point for determining the long-term avoided costs of solar energy. Accordingly, ELPC recommends that the Commission direct the Staff to reconvene the Solar Working Group, direct the company to participate and provide all necessary information, and provide a VOS analysis for the next biennial review proceeding.

The Commission agrees that, given the rapid changes to the energy landscape, and pursuant to MCL 460.6v(3), a biennial review of PURPA avoided costs is appropriate and that for purposes of Section 6v(1) this proceeding should be considered the initial five-year review for Consumers.

The Commission also agrees that the other rate elements of PURPA, namely, maintenance, backup, interruptible, and supplementary power, and other services, are being addressed in other proceedings and need not be addressed here.

The Commission also finds that ELPC's recommendation that a VOS analysis be undertaken is potentially duplicative, given the directive under the new energy legislation, which requires the Commission to create a distributed generation program and examine costs associated with distributed generation and net metering. MCL 460.1173 and MCL 460.6a(14). Accordingly, the Commission anticipates that VOS issues, as well as other avoided costs associated with distributed generation generally, will be examined as part of these proceedings, which will be completed before the next PURPA review.

THEREFORE, IT IS ORDERED that:

A. On or before June 12, 2017, the parties to this proceeding may file proposed inputs to be used for developing avoided capacity cost using a natural gas combustion turbine unit and avoided energy cost using a natural gas combined cycle unit as proxy plants and including investment cost attributable to energy. The parties shall at the same time file final, proposed avoided cost calculations and a proposed Standard Offer tariff, which includes all forecasts as described in the order.

B. Parties to this proceeding may file responses to the initial filings by June 19, 2017.

C. A hearing shall be conducted by Administrative Law Judge Mark E. Cummins at 9:00 a.m. on June 21, 2017. At the hearing, the Administrative Law Judge shall set a briefing schedule so that the Commission can read the record and issue a decision by July 12, 2017.

The Commission reserves jurisdiction and may issue further orders as necessary.

MICHIGAN PUBLIC SERVICE COMMISSION

Sally A. Talberg, Chairman

Norman J. Saari, Commissioner

Rachael A. Eubanks, Commissioner

By its action of May 31, 2017.

Kavita Kale, Executive Secretary